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Incorporating short-term operational plant constraints into assessments of future electricity generation portfolios

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HIGHLIGHTS

- Incorporating short-term operating constraints and dispatch into long-term generation planning.
- Short-term constrained dispatch increases overall costs due to higher running and start-up costs.
- Such cost increases can affect the choice of optimal generation portfolios.
- The operational impacts depend on the unit start/stop dispatch criteria, carbon price and technology mix.
- With high renewables, the impacts on the optimal portfolios and the overall costs are more significant.

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ABSTRACT

This paper presents a post-processing extension to a Monte-Carlo based generation portfolio planning tool in order to assess the short-term operational implications of different possible future generation portfolios. This extension involves running promising portfolios through a year of economic dispatch at 30-minute intervals whilst considering operational constraints and associated costs including minimum operating levels, ramp rate constraints and generator start-up costs. A case study of a power system with coal, combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT) and wind generation options highlights that incorporating operational criteria into the long-term generation investment and planning analysis can have operating, economic and emissions implications for the different generation portfolios. The extent of the impacts depends on the dispatch strategies; the carbon price; and the mix of technologies within the portfolio. As intermittent generation within power systems increases and carbon pricing begins to change the merit order, such short-term operational considerations will become more significant for long-term generation investment frameworks.

1. Introduction

Decision making in generation investment and planning requires a long-term perspective amidst considerable uncertainties including expected future demand, fuel prices, plant construction costs, and wider policy settings such as carbon pricing or energy security concerns. Given its complexity and long planning horizon, most long-term generation investment and planning frameworks often do not consider the actual details of short-term electricity industry operation such as generating unit constraints and inter-temporal generation dispatch [1]. Many of such frameworks are based on the use of a Load Duration Curve (LDC), which is a simplified representation of demand profile, to determine a future optimal generation technology mix. While LDC based approaches are useful and straightforward to apply, they generally involve significant assumptions. An example is the incorporation of uncertainty into the analysis. Another limitation, and the focus of this paper, is that the use of a LDC removes information regarding the chronology (sequencing over time) of electricity industry operation. Effectively, the generation portfolio is dispatched to meet this demand curve from highest to lowest without any consideration of actual changes in demand over time and its potential implications for the physical operation of the generation. In reality, however, many generation technologies have significant inter-temporal operating constraints such as minimum operating levels, ramp rates, and start-up and shutdown times. There can also be significant operating costs associated with some inter-temporal operating decisions such as unit commitment (plant start-up).

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The growing deployment of intermittent renewable generation sources, particularly wind and solar, increases the complexity of electricity industry operation including generation dispatch and scheduling [2], transmission grid operation and development [3] and ancillary services requirements [4]. Although renewables can hedge against the risk of fossil-fuel price volatility and reduce CO_2 emissions, they potentially pose significant operational challenges for conventional generating plants in the portfolio given their outputs are highly variable and somewhat unpredictable [5–7]. Conventional generating units may be required to ramp up/down and start/stop more frequently to accommodate the combined net variability of demand and renewable generation output, making the distribution of operating reserves and generation scheduling particularly important [8]. These changes are also likely to result in increased operating and maintenance costs.

With growing concerns regarding demand growth, climate change, and fossil-fuel price volatility, generation planning and investment methods have moved beyond just determining the least-cost generation mix to incorporate multiple objectives including cost-related risks, energy security, environmental impacts and social welfare [9,10]. In addition, uncertainties over critical cost factors including fossil price, climate change policies and plant investment costs have, to some extent, been taken into account in long-term generation planning and investment frameworks [11,12]. Generation portfolio planning frameworks are increasingly being applied in studies for analysing future generation investment and production scheduling from the perspective of both centralized electric utilities and individual power generation companies [13–15]. Mean Variance Portfolio (MVP) techniques have been widely employed to determine optimal future generation portfolio mixes with different cost and risk tradeoffs [16,17]. Such techniques have also been used to examine the role of non-fossil fuel generation technologies, such as nuclear and wind, in hedging against price risk due to uncertainties in future electricity prices, fossil-fuel prices and climate change policies [6,18]. Nevertheless, in a similar manner to many long-term planning frameworks, operational issues including unit constraints and inter-temporal generation dispatch are often overlooked in standard portfolio planning approaches [1]. Unfortunately these demand, energy security, and climate change concerns also have some significant implications for short-term electricity industry operation.

For these reasons there is growing value in incorporating potential operational and economic implications associated with the chronology of electricity industry operation into long-term generation investment and planning frameworks. Ignoring these aspects may lead to an inaccurate estimation of generation costs and emissions of generation portfolio options. Furthermore, some generation portfolios that appear attractive under standard long-term investment analysis might actually have questionable operational viability for expected demand patterns due to high levels of intermittent inflexible plant. A better understanding of short-term operational implications can help policy decision makers to identify appropriate options that can enhance the flexibility[1] of the electric system in order to accommodate high levels of renewable generation. This can be achieved through combinations of storage technologies, demand side options, expansion of transmission system infrastructure including smart grids, ancillary services and more sophisticated generation dispatch and unit commitment [19–21].

In previous work, a novel generation investment decision support modelling tool based on probabilistic generation portfolio analysis was presented for assessing future electricity generation portfolios under uncertainties [7,22]. The tool combines Monte Carlo extensions to traditional deterministic LDC techniques with portfolio assessment methods that include calculating the efficient frontier containing optimal generation portfolios. Despite the capability of the tool in addressing uncertainties associated with long-term generation investment and planning, there are inherent limitations in the tool's ability to incorporate issues related with short-term electricity industry operation.

This study proposes a new method for addressing this limitation. In particular, a 'post-processing' extension to the existing generation investment tool is implemented to incorporate generating unit constraints and inter-temporal generation dispatch. The post-processing extension is then applied to a case study using the data from the Australian National Electricity Market (NEM) in order to demonstrate the capability of this extension method. Case study findings and results are then used to provide a high-level assessment of the potential impacts of short-term operational aspects on the technical viability, economics and emissions of generation portfolios that appear favorable from the initial generation portfolio investment and planning framework. Note that not all operational issues associated with the electricity industry are incorporated as this represents an extremely challenging computational task. The post-processing assessment includes indices of possible violations of operating constraints such as number of starts/stops, ramp rates, the economic and emissions implications of different dispatch strategies around minimum plant operating levels.

There are some studies which incorporate operational aspects into generation portfolio planning frameworks. These aspects include generating unit characteristics and constraints as well as actual dispatch decisions to account for the variability of wind power and ramp limits of conventional plants [1,23]. For the conventional LDC optimal mix approaches, some of the operational aspects have also been incorporated into the analysis [24]. Nevertheless, these approaches, to date, have not generally included issues associated with cycling operation including starting and stopping of generating units as well as their associated costs.

This paper is organized as follows. Section 2 describes the Monte Carlo-based decision support tool including an example. The methodology for our post-processing extension is detailed in Section 3. Section 4 presents a case study. Results of the case study and its implications are discussed in Section 5 while Section 6 provides some concluding remarks.

2. Monte Carlo based decision support tool for generation investment and planning

The generation investment and planning decision support tool implemented in our previous work assesses the costs of possible future electricity generation portfolios given uncertain fuel prices, carbon prices, plant capital costs, and electricity demand. The tool extends conventional LDC methods by incorporating potentially correlated uncertainties for key cost assumptions and future demand using Monte Carlo Simulation (MCS). The expected costs, cost uncertainties and CO_2 emissions of a range of potential new-build generation portfolios in a given future year are directly obtained from several thousand scenarios with probabilistic input parameters. The cost spread for a generation portfolio can, for some distributions, be represented by variance and is referred to as 'cost uncertainty'. In our usage this carries a similar meaning to 'risk' in the economic and finance contexts. The tool applies financial portfolio analysis techniques to determine an efficient frontier containing optimal generation portfolios given possible tradeoffs between expected (average) cost and its associated cost uncertainty. The tool is not restricted to the use of normal distributions to model uncertainties therefore other forms of risk-weighted

[1] Flexibility implies the ability of a power system to withstand sudden and rapid changes in supply and demand in a reliable manner.